IN THE UNITED STATES PATENT & TRADEMARK OFFICE

Patent Application

For

SYSTEM AND METHOD FOR OPTIMIZING PRODUCTION IN AN ARTIFICIALLY LIFTED WELL

By

Julian R. Cudmore
Julian B. Haskell
Thomas M. White

SYSTEM AND METHOD FOR OPTIMIZING PRODUCTION IN AN ARTIFICIALLY LIFTED WELL

BACKGROUND OF THE INVENTION

Field of the Invention

[0001]   The present invention relates to artificially lifted oil and gas wells, and in particular to such wells employing gas lift technology.

Description of Related Art

[0002]   In many artificially lifted wells, there is potential for significantly improved operation and increased production. There are a variety of mechanisms for artificially lifting fluid from a reservoir, such as gas lift systems. In artificial lift systems, a variety of mechanical and systemic components can limit optimization of system usage. For example, gas injection rates may not be optimal and/or artificial lift system components may be blocked, damaged, sized improperly, operated at less than optimal rates, or otherwise present limitations on gaining optimal use of the overall system.

[0003]   Attempts have been made to detect certain specific problems. However, comprehensive analysis of the well and/or system components has proved to be difficult

once the system is moved downhole and placed into operation.

BRIEF SUMMARY OF THE INVENTION

[0004]   In general, the present invention provides a system and method of optimizing production in a well having a gas lift system. The gas lift system is located and operated within a wellbore. Simultaneously, a plurality of production parameters are monitored and used to obtain certain desired, measured data indicative of well operational factors. The measured data are evaluated according to an optimization model to determine if production is optimized. If not, the gas lift mechanism is redesigned based on evaluation of the various production parameters and measured data.

BRIEF DESCRIPTION OF THE DRAWINGS

[0005]   Certain embodiments of the invention will hereafter be described with reference to the accompanying drawings, wherein like reference numerals denote like elements, and:

[0006]   Figure 1 is a schematic illustration of a methodology for optimizing production in a well, according to an embodiment of the present invention;

[0007]   Figure 2 is an elevational view of a gas lift system utilized in a well to lift fluids to a surface

location, according to an embodiment of the present invention;

[0008]   Figure 3 is a flowchart representing a method of selecting and optimizing production in a well, according to an embodiment of the present invention;

[0009]   Figure 4 is a diagramatic illustration of an embodiment of a control system that can be used to automatically carry out the methodology or portions of the methodology illustrated in Figure 3;

[0010]   Figure 5 is an illustration of parameters utilized in candidate selection;

[0011]   Figure 6 is an illustration of a system that can be used to acquire data for use by the well optimization methodology illustrated in Figure 3;

[0012]   Figure 7 is an illustration of an embodiment of a well performance model;

[0013]   Figure 8 is a graph representing a comparison of measured data to calculated data;

[0014]   Figure 9 is a graph similar to that of Figure 8 but following redesign of the artificial lift system;

[0015]   Figure 10 is a graphical representation of factors that can affect gas lift redesign;

[0016]   Figure 11 is a graphical representation of correlation examples that can be used to facilitate gas lift redesign;

[0017]   Figure 12 is a graphical representation of potential corrective actions that can be taken to optimize production from the well illustrated in Figure 2;

[0018]   Figure 13 is a flowchart illustrating a selected methodology of the present invention for optimizing gas injection rate;

[0019]   Figure 14 is a flowchart illustrating a portion of the methodology of Figure 13 when the well flows and takes gas;

[0020]   Figure 15 is a flowchart illustrating a portion of the methodology of Figure 13 when the well flows and does not take gas; and

[0021]   Figure 16 is a flowchart illustrating a portion of the methodology of Figure 13 when the well flows and the gas injection is irregular.

DETAILED DESCRIPTION OF THE INVENTION

[0022]   In the following description, numerous details are set forth to provide an understanding of the present invention. However, it will be understood by those of ordinary skill in the art that the present invention may be practiced without these details and that numerous

4

variations or modifications from the described embodiments may be possible.

[0023]   The present invention generally relates to a system and method for optimizing production from a well in which fluids are lifted by a gas lift system deployed in the well.   The process allows the artificial lift system to be analyzed and diagnosed to facilitate system redesign that optimizes performance with respect to the productivity of the well.

[0024]   A general approach to optimization is set forth in the flowchart of Figure 1.   Initially, underperforming, artificially lifted wells are identified, as set forth in block 20.   Upon determining the underperforming wells, the cause of the underperformance is identified, as illustrated by block 22.   Identification of the cause of the underperformance enables the implementation of corrective procedures, e.g. gas lift redesign, as illustrated in block 24. Effectively, a cause or problem is identified and an effect or correction is undertaken to optimize performance. Depending on the environment and the specific equipment used, the causes and the selected effects, i.e., corrective actions, may vary as discussed more fully below.

[0025]   Although this general approach can be applied to a variety of artificially lifted wells, the present description will primarily be related to the optimization of a well in which a gas lift system is used to artificially lift the well fluid.   In Figure 2, an embodiment of a gas lift system 26 is illustrated.   In this

embodiment, gas lift system 26 is used to produce fluid from a wellbore 28 drilled or otherwise formed in a geological formation 30. A wellbore section of the gas lift system 26 is suspended below a wellhead 32 disposed, for example, at a surface 34 of the earth. A tubing 36 provides a flow path within wellbore 28 through which well fluid is produced to wellhead 32.

[0026]   As illustrated, wellbore 28 is lined with a wellbore casing 38 having perforations 40 through which fluid flows from formation 30 into wellbore 28. For example, a hydrocarbon-based fluid may flow from formation 30 through perforations 40 and into wellbore 28 adjacent an intake 42 of tubing 36. Upon entering wellbore 28, the well fluid is produced upwardly by gas lift system 26 through tubing 36 to wellhead 32. From wellhead 32, the produced well fluid is directed through control valve 44 to a separator 46 where gas and liquid are separated. The substantially liquid portion of well fluid is directed to a desired location, such as stock tank 48.

[0027]   Although gas lift system 26 may comprise a wide variety of components, the example in Figure 2 is illustrated as having a gas compressor 50 that receives an injection gas from a gas source, such as separator 46. Gas compressor 50 forces the gas through a flow control valve 52, through wellhead 32 and into the annulus between tubing 36 and casing 38. A packer 54 is designed to seal the annulus around tubing 36. (In the embodiment illustrated, packer 54 is disposed proximate intake 42.) The pressurized gas flows through the annulus and is forced

into the interior of tubing 36 through one or more gas lift valves 56 disposed in corresponding side pocket mandrels 58. The gas flowing through gas lift valves 56 draws well fluid into intake 42 and upwardly through the interior of tubing 36. The mixture of injected gas and well fluid move upwardly through control valve 44 and are separated at separator 46 which directs the well fluid to stock tank 48 and the injection gas back to gas compressor 50.

[0028] One example of a methodology that can be used in optimizing production in a gas lifted well can be described with reference to the illustrated flowchart of Figure 3. Initially, the candidate wells are selected based on an indication of underperformance (block 60). In the selected well or wells, a preliminary analysis (block 62) is made to verify the candidate well is not producing at an optimal level and is suitable for production optimization. Subsequently, data is acquired that will help gauge the performance of the gas lift system 26 (block 64). The data is based on a variety of production related parameters that may be sensed or otherwise obtained. In many applications, the sensing of production related parameters in real-time substantially improves the accuracy and comprehensiveness of the "operational picture" used in analyzing potential problems that contribute to underperformance. Once the data is acquired, the well is modeled based on known parameters related to the well and the specific gas lift system. The modeled well can then be matched to measured data, e.g. data based on the sensed production parameters, as illustrated in block 66. If the well is operating at a sub-optimal level, a gas lift redesign is implemented and

7

validated (block 68). It should be noted that although the gas lift system is a major factor in the outflow performance of a well, the lift system is codependent with other factors, such as reservoir inflow and surface system performance. Thus, the optimization methodology benefits from an understanding of well performance, including inflow, outflow and surface performance, in determining the cause of sub-optimal performance.

[0029] Some or all of the methodology outlined with reference to Figure 3 is automated via a processing system 70, as diagramatically illustrated in Figure 4. Processing system 70 may be a computer-based system having a central processing unit (CPU) 72. CPU 72 is operatively coupled to a memory 74, as well as an input device 76 and an output device 78. Input device 76 may comprise a variety of devices, such as a keyboard, mouse, voice-recognition unit, touchscreen, other input devices, or combinations of devices. Output device 78 may comprise a visual and/or audio output device, such as a monitor having a graphical user interface. Additionally, the processing may be done on a single device or multiple devices located at the well, away from the well, or with some devices located at the well and other devices located remotely.

[0030] Processing system 70 can be used to input parameters regarding candidate selection. The system also can be used to receive data during the data acquisition phase, to model the well by comparing calculated or modeled values to measured data, and to facilitate gas lift redesign based on the measured data. However, it should be

recognized that the design and implementation of processing system 70 can vary substantially from one application to another, and the desired interaction between processing system 70 and an optimization technician may vary based on design considerations and application constraints.

[0031]   As briefly described with reference to Figure 3, candidate wells are initially selected. In, for example, oilfields with high populations of gas lift systems, it is important that likely candidates for optimization are filtered from wells that are already running at optimum conditions and at optimum rates. In one approach, candidate selection may be used to filter out wells according to priority of potential oil production gain, thereby helping attain maximum success in a minimum timeframe. The recognition of sub-optimally lifted wells relative to other wells in the field is not a straightforward task and requires evaluation of various data and information.

[0032]   The ability to determine likely candidates for optimization often relies on obtaining accurate data related to the subject wells. For example, it can be useful to monitor a data trend to determine the consistency and accuracy of the data relied on in determining likely candidates for optimization.

[0033]   Also, it can be important to initially examine a variety of factors before selecting candidates for optimization. In Figure 5, four candidate selection factors are illustrated, specifically, well test data 80,

available gas lift monitoring data 82, completion data 84, and well history 86.

[0034]   When interpreting existing well test data, it is beneficial to understand the accuracy level of the data and how it was acquired. Therefore, before selecting candidates it is helpful to examine any raw data related to production. For example, a differential pressure chart indicates the gas injection rate behavior, and a water cut reading of samples can indicate stability of the water cut. If the historical data is not consistent or cannot be logically analyzed, it may be necessary to test the well to establish "baseline" production values. After preliminary screening, the most prominent optimization candidates can be selected.

[0035]   Available gas lift monitoring data also can affect candidate selection. During historical operation of a gas lift, certain parameters may be measured and values recorded on a periodic basis. Any of this monitoring data, e.g. gas injection rate, gas injection line pressure, casing head pressure, wellhead pressure, and wellhead temperature, can be helpful in assessing the potential for production optimization.

[0036]   Completion data also is a factor that can affect the potential for production optimization. A review of a completion design diagram provides valuable information as to the gas lift configuration and specific downhole equipment used in the system. Such information may include depth and type of mandrels, type of gas lift valves, and

10

port sizes. The configuration and equipment can help provide a better understanding of well behavior.

[0037]   Well history data can also provide information that will aid in candidate selection. Well history data can include flowing gradient surveys, well intervention and stimulation information, records of chemical treatment, and other information that can help provide a basic understanding of the well. All of these factors can be used to reduce the subjectivity of the candidate selection process.

[0038]   Upon selecting a candidate well, data is acquired to gauge the performance of the gas lift system. Typically, data is acquired by a variety of sensors that may comprise, for example, distributed temperature sensors and pressure sensors. Also, it can be beneficial to utilize sensor systems able to provide real-time streaming data. Trended data with common time and date facilitates the selection of points of interest from trend lines to provide more accurate "snap shots" of well operation to aid in analysis.

[0039]   In Figure 6, an embodiment of a sensor system used to facilitate optimization of a gas lift system is illustrated. The various sensors may be coupled to processing system 70 which is able to assimilate the data and display relevant information to a technician and/or utilize the data in performing analyses on the well. Although a variety of parameters may be sensed to provide measured data that can be used in analysis of a given well,

Figure 6 illustrates examples of sensors and sensed parameters that may be helpful to the analysis. The sensed parameters are divided into three example groups, including surface measurements 88, downhole measurements 90, and episodic measurements 92. Many of the sensed parameters can be obtained in real-time and delivered to processing system 70 for analysis. Processing system 70 can be located locally at the well or remotely. If located remotely, signals from the sensors can be transmitted to processing system 70 by hardwire or wirelessly, e.g. via satellite communication. Additionally, processing system 70 may comprise a single unit or multiple linked units.

[0040]   Examples of surface sensors and/or sensed parameters include tubing pressure and temperature sensors 94, injection pressure and temperature sensors 96, injection sensors 98 for sensing the gas injection rate, and multiphase flow sensors 100. Examples of downhole sensors and/or sensed parameters include tubing pressure sensors 102 disposed below the orifice, casing pressure sensors 104 disposed below the orifice, and distributed temperature sensors 106. Examples of episodic sensors include sensors 108 for determining a flowing gradient survey and a deployable distributed temperature sensing (DTS) system 110 that may be deployed, for example, by a slickline. In other applications, it may be desirable to utilize additional sensors, other sensors, or smaller groups of sensors than those illustrated. For example, in some applications, the methodology discussed herein may be carried out with a unique subset of the illustrated sensors, such as sensors 94, 96, 98, 100, 108, and 110.

12

Additionally, commercially available systems may be suitable to determine at least some of the measured data. An example of a commercially available system is the PhaseTester portable multiphase well testing system available from Schlumberger Technology Corporation of Sugar Land, Texas, USA.

[0041]   In addition to acquiring data, the subject well and the gas lift system is modeled. However, modeling of the well will vary depending on the environment in which the wellbore is drilled, formation parameters, and type and componentry of the gas lift system. Proper modeling of the well enables comparison of calculated values (model values) to measured data based on the various production related parameters sensed or otherwise obtained. As illustrated in Figure 7, a well performance modeling program 112 can be utilized on processor system 70 to match calculated or model values to the corresponding measured data 114 based on actual production related parameters, such as those described above with reference to Figure 6.

[0042]   A main philosophy in well modeling is the matching of a model well, e.g. optimized well, to measured data from the actual well to determine areas of sub-optimal performance. However, the more invalidated or unknown parameters used in the model, the greater the uncertainty and the greater the number of assumptions that must be used in the modeling. This, of course, increases the difficulty in matching the model with actual data in any meaningful way. Furthermore, the model and specific calculated data used to prepare a model for comparison to measured data can

vary substantially depending on the well, wellbore environment, type of artificial lift equipment, and variety of lift system components. In preparing a well model, it can be helpful to utilize a modeling program on processing system 70. One example that can be used in modeling gas lift systems is a software tool known as PIPESIM which provides steady-state, multiphase flow simulation for oil and gas production systems and is also available from Schlumberger Technology Corporation.

[0043]   As briefly discussed above, real-time collection of data from a wide variety of sensors and the use of that data in assimilating measured data for comparison to a predetermined model lays important groundwork for optimization of a given well. Potentially, the performance modeling program 112 can be used to model a variety of well-related performance characteristics. Typically, the program will prompt a user, via output device 78, for well related parameters that can be used to model one or more aspects of the subject well. The performance modeling program 112 also receives actual data from, for example, sensors such as those illustrated and described with respect to Figure 6. The contrast between the model characteristics and the actual measured data can be presented to a technician through output device 78. For example, the comparison can be presented graphically, as illustrated in Figure 8.

[0044]   In the example illustrated in Figure 8, the calculated variable is inlet pressure. The modeling program utilizes the wellhead pressure obtained from a

flowing gradient survey and the liquid rate that can also
be obtained from the flowing gradient survey. Vertical
flow correlations to be checked against the flowing
gradient survey are selected using engineering judgment. A
gradient 116 is calculated by the performance modeling
program 112 and graphically displayed via output device 78,
as illustrated. In this example, gradient 116 is
illustrated in graphical form on a graph 118 that plots
"pressure" along the x-axis against "elevation" along the
y-axis.

[0045]   The specific gradient 116 can be determined based
on a variety of known correlations. For example, a
correlation known as the Hagedorn and Brown (HBR)
correlation is used to provide the illustrated gradient
116. A second gradient 120, based on measured data, also
is plotted on graph 118. Thus, the modeled or calculated
gradient can be compared to the actual measured data. In
this example, a substantial pressure difference is
illustrated between the calculated pressure and the
measured pressure, particularly at greater depths. As a
result, corrective action can be taken and the measured
data re-plotted against the model gradient, as illustrated
in Figure 9. Although the appropriate corrective action
can vary substantially from one well/application to
another, the optimization illustrated in Figure 9 resulted
from increasing the "hold-up" factor which essentially
increased the weight of the hydrostatic column.

[0046]   As described above, well optimization sometimes
can result from simple adjustments to the gas lift system

design. However, other modeling results can indicate more substantial redesigns. In either situation, a thorough understanding of the well and the conditions in the well over time can greatly improve the gas lift redesigns. As illustrated in Figure 10, gas lift redesigns can benefit from a variety of factors, such as selecting the best correlations for use in modeling (block 122), obtaining accurate information related to the completion (block 124) and the reservoir (block 126). Other factors can include knowledge of fluid properties (block 128) and surface parameters (block 130).

[0047]   Examples of completion related information that can be useful in gas lift design include type of completion, tubing size, casing size, and any deviations of the well. Well deviation, for example, can affect the inflow and outflow performance of the well and the type of gas lift mandrel suitable for optimum production from such wells. Useful reservoir information may include the type of producing sand, the static bottomhole pressure or reservoir pressure, the static bottomhole temperature, permeability, sand thickness, skin and water leg. Examples of useful fluid properties include viscosity, bubble point pressure, gas-oil-ratio, API gravity data, gas specific gravity, and water salinity. Useful surface information may include separator pressure, flow line considerations, and compressor pressure. Many of these gas lift and environmental factors also can influence the design of modeling programs for modeling a given well or wells.

[0048]   Along those same lines, the effectiveness of the modeling also greatly influences gas lift redesign and the ability to optimize performance in a given well. It is not only the quality of the data input in a given modeling program but also the correlations used in the model. Some correlations between calculated values and measured data can be more important than others. For example, in redesigning gas lift systems, examples of correlations that can play an important role are illustrated in Figure 11 and include bubble point pressure correlations 132, oil viscosity correlations 134, and multiphase flow correlations 136. The redesign may involve a simple setting readjustment, such as adjusting a temperature setting or adjusting the gas injection rate. However, the redesign also may involve more substantial changes to the gas lift system, such as changing components of the gas lift system.

[0049]   As illustrated in Figure 12, various corrective actions 138 can be taken to optimize production from the subject well based on indications of problem areas from the well modeling. With gas lift systems, the corrective action typically is related to inlet options 140, outlet options 142, and downhole options 144. Determination of potential corrective actions can be performed automatically by processing system 70, or processing system 70 can be designed to output an indication of deviation between modeled values and measured data, e.g. Figure 8, for review by a technician.

[0050]   By way of example, high casing pressure or
excessive gas usage relative to model values may indicate
an inlet problem, such as a choke sized too large. A
showing of excessive gas usage can, for example, be
indicative of an inlet problem, such as high casing
pressure. Other deviations from model parameters can
indicate outlet problems, such as valve restrictions, high-
back pressure, and improper separator operating pressure.
Other deviations can indicate downhole problems, such as a
hole in the tubing, a well blowing dry gas, a well that
will not take any input gas, valve spacing that is too
wide, and other downhole problems. A wide variety of such
problems can be corrected to optimize production from the
well.

[0051]   After taking a corrective action or actions, the
results may be validated, as illustrated by block 146 in
Figure 12. This assessment can be an important part of the
redesign, because it serves to check whether production
from a given well has been improved and, if so, whether the
well production has been fully optimized. In the final
optimization, as illustrated by block 148, the well is
operated, and measured data is again compared to the well
model to determine the existence of any remaining
discrepancies indicating sub-optimal performance. Final
well optimization can also involve reviewing data from an
entire production network to determine whether changes to a
single well has affected the performance of the overall
production network.

[0052]   By way of example, Figures 13-16 illustrate one selected methodology of the present invention for optimizing gas injection rate. Referring to Figure 13, following identification of an underperforming well, a flowing survey of the well is taken (block 1302). The continuous flow design diagnostics of the present invention, described above, are then applied (block 1304). As illustrated, the well does (block 1306) or does not (block 1308) flow.

[0053]   Assuming, for example, that the well flows, it will take gas (block 1310), not take gas (block 1312), or take gas irregularly (block 1314). Figure 14 illustrates the methodology when the well flows and takes gas (block 1402). Under these circumstances, injection will either be through a gas lift valve (block 1404) or not (block 1406). If injection is through a gas lift valve which is the deepest valve (block 1408), a reevaluation of the system must be made (block 1410) to determine whether or not the gas injection rate is optimized (block 1412).

[0054]   If the injection is not through the deepest gas lift valve (block 1408), an evaluation must be made for a deeper point (block 1414) before checking for mechanical problems (block 1416). If no mechanical problems are found, the system is redesigned for deeper injection (block 1418) before reevaluation (block 1410). If mechanical problems are found, the restriction must be removed (block 1420) and workover must be considered (block 1422) before reevaluation (block 1410).

[0055]   If injection is not through a gas lift valve (block 1406), there may either be a hole in the tubing (block 1424) or a leak in the sidepocket mandrel (block 1426).   In case of a hole in the tubing, a packoff is installed (block 1428) before the system is reevaluated (block 1410).   In case of a sidepocket mandrel leak, the gas valve is reinstalled (block 1430) before installation of a packoff (block 1432) and reevaluation of the system (block 1410).

[0056]   Figure 15 illustrates the methodology when the well flows but does not take gas (block 1502).   Under these circumstances, there may be a failed gas lift valve (block 1504), a casing bridge (block 1506), and excessively high gas lift valve setting (block 1508), an excessively low gas lift valve design temperature (block 1510), or a surface gas input problem (block 1512).   The remedial actions are, respectively, to change the gas lift valve (block 1514), to pump chemical (block 1516) followed by water (block 1517), redesign the gas lift valve for a lower pressure (block 1518), redesign the gas lift valve for a higher temperature (block 1520), or check for a plugged or frozen choke (block 1522).   In each case, following the specified remedial action the system is reevaluated (block 1524) to ascertain that the gas injection rate is optimized (block 1526).

[0057]   Figure 16 illustrates the methodology when the well flows, but gas injection is irregular (block 1602). Under these circumstances the problem will be either a subsurface problem (block 1604) or a surface problem (block 1606).   A subsurface problem will manifest itself in either

20

low (block 1608) or high (block 1610) casing pressure. When a low casing pressure is evident, there may be a hole in the tubing (block 1612), the unloading valve may have lost pressure (block 1614), the valve port fluid may be cut (block 1616), or the sidepocket mandrel may be leaking (block 1618). Once the cause of the low casing pressure is ascertained and remedied, the system is reevaluated (block 1620) to determine if the gas injection rate optimized (block 1622).

[0058]   When a high casing pressure is evident, the unloading valve may have gained pressure (block 1624), the gas lift valve may be operating too deep (block 1626), or the valve port size may be too small (block 1628). Upon diagnosing the cause of the high casing pressure and correcting the problem, the system is reevaluated (block 1620) to determine if the gas injection rate is optimized (block 1622).

[0059]   A surface problem (block 1606) may be reflected in, for example, an unstable gas supply (block 1630) or an unstable back pressure (block 1632). Unstable gas supply pressure may be due to an unstable compressor discharge (block 1634), in which case a redesign for higher (block 1636) should be undertaken before reevaluation (block 1620) and optimization of the gas injection rate (block 1622).

[0060]   Finally, unstable back pressure (block 1632) may be due, for example, to an adjacent well heading in a shared manifold (block 1638) or an unstable separator back pressure (block 1640) which should be corrected before

21

reevaluation (block 1620) and optimization of gas injection rate (block 1622).

[0061]   Although, only a few embodiments of the present invention have been described in detail above, those of ordinary skill in the art will readily appreciate that many modifications are possible without materially departing from the teachings of this invention. Accordingly, such modifications are intended to be included within the scope of this invention as defined in the claims.